NON-PUBLIC?: N
ACCESSION #: 9108140156
LICENSEE EVENT REPORT (LER)

FACILITY NAME: COMANCHE PEAK - UNIT 1 PAGE: 1 OF 8

DOCKET NUMBER: 05000445

TITLE: REACTOR TRIP RESULTING FROM ERRATIC OPERATION OF THE MAIN TURBINE
ELECTROHYDRAULIC CONTROLLER
EVENT DATE: 07/13/91 LER #: 91-020-00 REPORT DATE: 08/12/91

OTHER FACILITIES INVOLVED: N/A DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 080

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: D.E. BUSCHBAUM COMPLIANCE TELEPHONE: (817) 897-5851
SUPERVISOR

COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

On July 13, 1991, Comanche Peak Steam Electric Station Unit 1 was in Mode 1, Power Operation, with the reactor at 80 percent of rated thermal power. In preparation for troubleshooting a seal problem on one of the main turbine electrohydraulic controller fluid pumps, the idle pump was started and one of the operating pumps was secured. Following the pump start, air entrained in the fluid flow caused rapid and erratic operation of the main turbine steam control valves. This created a pressure pulse which propagated up the main steam line to the steam generator causing a spike of sufficient magnitude on the steam generator narrow range level transmitter to exceed the Hi-Hi level setpoint. The resulting turbine trip initiated a reactor trip. The root cause of the event will be verified by testing to be performed during a forthcoming outage. Corrective actions include testing and design modification.

END OF ABSTRACT

I. DESCRIPTION OF THE REPORTABLE EVENT

A. REPORTABLE EVENT CLASSIFICATION

Any event or condition that resulted in a manual or automatic actuation of any Engineered Safety Feature (ESF) including the Reactor Protection System.

B. PLANT OPERATING CONDITIONS PRIOR TO THE EVENT

On July 13, 1991, just prior to the event, Comanche Peak Steam Electric Station (CPSES) Unit 1 was in Mode 1, Power Operation, with reactor power at 80 percent.

C. STATUS OF STRUCTURES, SYSTEMS, OR COMPONENTS THAT WERE INOPERABLE AT THE START OF THE EVENT AND THAT CONTRIBUTED TO THE EVENT

There were no inoperable structures, systems or components that contributed to the event.

D. NARRATIVE SUMMARY OF THE EVENT, INCLUDING DATES AND APPROXIMATE TIMES

On July 12, 1991, at approximately 2200 hours CDT, a reduction in reactor power was commenced to place the plant in a condition allowing: (1) performance of periodic testing of the main turbine high pressure (HP) and low pressure (LP) stop and control valves (EIIS:(V)(JJ)), and (2) troubleshooting of one of the three main turbine electrohydraulic controller (EHC) fluid pumps (EIIS:(P)(JJ)). Reactor power was stabilized at 80 percent, and on July 13 at approximately 0139 hours, testing of the HP and LP stop and control valves was successfully completed. At 0140 hours the Reactor Operator (utility, licensed) initiated actions to return reactor power to 100 percent.

A previously identified problem with the EHC fluid pump motor bearing seal (EIIS:(SEAL)(JJ)) on Pump A had resulted in the introduction of EHC fluid into the motor bearing and winding area. Monitoring of the differential pressure between the EHC fluid reservoir (EIIS:(RVR)(JJ)) and motor space heater cavity was planned to gather data for a future modification to the seal design. At 0145 hours control fluid

Pump A was started and Pump B was secured, leaving Pumps A and C in operation. At 0154 hours Hi-Hi level signals on steam generators (EIIS:(SG)(SB)) 1 and 2 resulted in a trip of the main turbine (EIIS:(TRB)(TA)). Since reactor power was above 50 percent, the turbine trip resulted in a reactor trip. Additional reactor trip signals were generated due to Lo-Lo level signals from all four steam generators.

Control Room personnel responded in accordance with emergency operating procedures, and at 0220 hours the plant was stabilized in Mode 3, Hot Standby. At 0412 hours, the NRC was notified of the event via the Emergency Notification System in accordance with 10CFR50.72.

E. THE METHOD OF DISCOVERY OF EACH COMPONENT OR SYSTEM FAILURE, OR
PROCEDURAL OR PERSONNEL ERROR

Numerous alarms (EIIS:(ALM)(IB)) received in the Control Room identified the immediate cause of the reactor trip to be the turbine trip caused by the apparent Hi-Hi level in steam generators 1 and 2. Evaluation of recorded data immediately following the event revealed that a total of nine generator output load swings occurred immediately following pump switchover. The magnitude of the load swings was approximately 50 megawatts, and occurred at random intervals. These secondary plant oscillations resulted in fluctuations in indicated steam generator levels, culminating in momentary spikes on steam generators 1 and 2 level instrumentation (EIIS:(LI)(JB)) which exceeded the Hi-Hi level setpoint. The conditions which led to the control system fluctuations were determined during the engineering evaluation of the event performed by the plant engineering staff and the vendor representative.

II. COMPONENT OR SYSTEM FAILURES

A. FAILURE MODE, MECHANISM, AND EFFECT OF EACH FAILED COMPONENT

There have been no failed components identified as having contributed to this event.

B. CAUSE OF EACH COMPONENT OR SYSTEM FAILURE

No failed components have been identified.

C. SYSTEMS OR SECONDARY FUNCTIONS THAT WERE AFFECTED BY FAILURE OF
COMPONENTS WITH MULTIPLE FUNCTIONS

No failed components have been identified.

D. FAILED COMPONENT INFORMATION

No failed components have been identified.

III. ANALYSIS OF THE EVENT

A. SAFETY SYSTEM RESPONSES THAT OCCURRED

As a result of the Hi-Hi steam generator level signal, a turbine trip signal, steam dump signal, and feedwater isolation signal were generated; those functions actuated and all associated components performed as designed. As a result of the Lo-Lo steam generator level signal, an auxiliary feedwater actuation signal and steam generator blowdown and sampling isolation signal were generated. The Turbine Driven Auxiliary Feedwater (TDAFW) pump (EIIS:(P)(BA)) did not start, and the steam generator blowdown and sampling isolation did not occur because of the very short period of time that the steam generator Lo-Lo level signal was active.
he seal-in feature
for the TDAFW pump start is implemented by a limit switch (EIIS:(ZIS)(BA)) associated with the turbine steam supply valve. A similar configuration exists for the steam generator blowdown and sampling isolation valves. Following receipt of an actuation signal, sufficient valve movement must occur to effect seal-in. During the July 13 event, the actuation signals were active for no longer than one eighth of a second, an insufficient time to allow the valves to move off the associated limit switches.

B. DURATION OF SAFETY SYSTEM TRAIN INOPERABILITY

There were no safety systems or components rendered inoperable during or as a result of the event.

C. SAFETY CONSEQUENCES AND IMPLICATIONS OF THE EVENT

The turbine the event resulting in a reactor trip is discussed in Section 15.2.3 of the CPSES Final Safety Analysis Report. The analysis uses conservative assumptions to demonstrate that Departure from Nucleate Boiling Ratio will never decrease below the limiting value of 1.30 during the event. The event of July 13, 1991, occurred at 80 percent reactor power, and all protective functions responded as required. The event is completely bounded by the FSAR accident analysis which assumes an initial power level of 102 percent and makes conservative assumptions which reduce the capability of safety systems to mitigate the consequences of the transient. It is concluded that the event of July 13 did not adversely affect the safe operation of CPSES Unit 1 or the health and safety of the public.

IV. CAUSE OF THE EVENT

A. IMMEDIATE CAUSE

The reactor trip was caused by a turbine trip initiated by apparent Hi-Hi levels on steam generators 1 and 2.

B. INTERMEDIATE CAUSES

During event evaluation, a number of possible causes of the erratic control system behavior were postulated. Each postulated cause and its resultant anticipated effect on control system behavior was evaluated against data recorded during the event and/or previous operating experience with the system. This systematic review led to the conclusion that the event was caused by the accumulation of air in the idle EHC control fluid pump or discharge piping, resulting in air entrainment in the fluid flow following pump switchover. As the entrained air bubbles swept past the controlling edge of the pilot valves, minor variations in system response led to rapid and erratic movement of the main turbine steam control valves.

It has been observed that rapid closure of turbine control valves or the opening of atmospheric relief valves or steam dump control valves can result in a pressure pulse phenomenon which may be sensed by the steam generator level transmitters. The

pressure wave travels upstream to the steam generators with the potential for causing low and/or high pressure spikes of a magnitude sufficient to exceed the Low- Low or Hi-Hi level setpoints.

C. ROOT CAUSES

Continued operation of the affected system precludes performance of the testing activities required to confirm the causes leading to the accumulation of air in the EHC fluid system. However, further evaluation will focus on two potential sources.

(1) An inherent design characteristic of the EHC system allowed the accumulation of air in the idle pump and/or discharge piping. Differential pressures existing within the system may have allowed the gradual introduction of air into the fluid system. This air was introduced into the fluid flow following the pump start.

(2) Less than adequate post work testing allowed an air pocket introduced during maintenance on the system to go undetected. During the recent mid-cycle outage, the EHC control fluid pump discharge check valves were reworked to correct a valve seating problem. The maintenance activity may have introduced air into the system which remained in the pump and/or discharge piping until the pump switchover performed just prior to the event.

An additional cause of the event has been determined to be the sensitivity of the steam generator narrow range level instrumentation to pressure pulses of very short duration but relatively high magnitude, such as those generated during rapid movement of the main turbine steam control valves. These pressure waves propogate upstream to the water filled impulse lines of the steam flow transmitters and steam generator narrow range level transmitters. Evaluation of recorded data revealed that the steam generator Hi-Hi level trip signal was active on

Steam Generator 1 for .123 seconds and on Steam Generator 2 for .125 seconds. These short duration signals were not an actual indication of steam generator inventory, and initiated an unnecessary reactor trip.

D. CONTRIBUTING FACTOR

The EHC fluid pump motor bearing seal problem is considered to be a contributing factor to the event. The current seal design allows EHC fluid to seep up the pump shaft into the motor cavity, creating the potential for motor damage and possible failure. The urgency for correcting the problem contributed to the decision to perform troubleshooting activities with the system operating. Those troubleshooting activities required the EHC pump switchover which flushed air accumulated in the system into the fluid flow.

V. CORRECTIVE ACTIONS

A. IMMEDIATE

During the plant startup following the reactor trip event, proper operation of the electrohydraulic control system was verified by testing or monitoring activities, including the following: correct accumulator pressures were verified; the proper relationship between the load limit device position indication and actual control valve position was checked; the pump discharge pressure and proper check valve operation were verified and; the minimum flow line was confirmed to be completely filled with oil.

B. ACTIONS TO PREVENT RECURRENCE

Potential cause: Air accumulation in control system

Corrective action: Testing will be performed during a forthcoming outage to gather data for further evaluation of the design and operational characteristics of the control system. The need for further action will be determined at that time.

Potential cause: Less that adequate post-work testing

Corrective action: The continued accumulation of operating experience with the turbine control system has led to an increased awareness of system sensitivity and the need for thorough testing following maintenance.

Cause: Sensitivity of steam generator level instrumentation

Corrective action: A design modification has been initiated to install a filter card with a lag time constant in the steam generator narrow range level instrumentation channels. The modification will minimize unnecessary ESF actuations from both Hi- Hi and Lo-Lo level signals.

Contributing factor: EHC fluid pump motor bearing seal problem

Corrective action: Data collected during pressure monitoring of the control system has been provided to the vendors design group for use in developing an improved seal design. It is anticipated that permanent installation of redesigned seals will eliminate the seal leakage problem and improve system reliability.

VI. PREVIOUS SIMILAR EVENTS

There have been no previous reactor trips attributable to the causes identified during event evaluation.

ATTACHMENT 1 TO 9108140156 PAGE 1 OF 1

TUELECTRIC Log # TXX-91257
File # 10200
910.4
Ref. # 50.73(a)(2)(iv)

August 12, 1991

William J. Cahill, Jr.
Executive Vice President

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NO. 50-445
MANUAL OR AUTOMATIC ACTUATION OF ANY ENGINEERED SAFETY

FEATURE
LICENSEE EVENT REPORT 91-020-00

Gentlemen:

Enclosed is Licensee Event Report 91-020-00 for Comanche Peak Steam Electric Station Unit 1, "Reactor Trip Resulting From Erratic Operation of the Main Turbine Electrohydraulic Controller."

Sincerely,

William J. Cahill, Jr.

By: A. B. Scott, Jr.
Vice President, Nuclear Operations

OB/bm

c - Mr. R. D. Martin, Region IV
Resident Inspectors, CPSES (2)

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